BEFORE THE STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL

IN RE APPLICATION NO. 2002-01 BP WEST COAST PRODUCTS, LLC BP CHERRY POINT COGENERATION PROJECT	**EXHIBIT 22.0 (BRP – T)**

APPLICANT'S PREFILED DIRECT TESTIMONY

BRIAN R. PHILLIPS

Q. Please state your name and business address for the record.

A. Brian Phillips, 1117 N.E. 135th Street, Seattle, Washington, 98125.

Q. What topics will your testimony address?

A. My testimony will address the following topics:

1. My background and experience.
2. The Cogeneration Project's emission control technology.
3. The Cogeneration Project's emissions.

4. The offsetting emission reductions at the BP Refinery.

5. The existing air quality in the vicinity of the project site.

6. The expected effect of the Cogeneration Project on ambient air quality.

7. Startup emissions and their effect on ambient air quality.

8. The expected effect of the Cogeneration Project on visibility.

Background and Experience

Q. What's your occupation?

A. I am an air quality engineer for the private consulting firm AirPermits.com.

Q. Please describe your education and background.

A. I received a Bachelor's of Science degree in Chemical Engineering at the University of California at San Diego. For the past 11 years, I have worked as a private consultant performing air quality monitoring and assisting clients in obtaining air quality permits.

Q. What has been your role in connection with the Cogeneration Project?

A. BP retained AirPermits.com to prepare the air quality section of the EFSEC Application for Site Certification, including the PSD application, which is found in Part III, Appendix E of the Application. Walt Russell and I have performed the emissions calculations, emission control evaluation, and air quality modeling associated with that application. We have met with members of Ecology's air division and EFSEC staff regarding the PSD application and related analysis. I have also attended several meetings regarding the project with Canadian regulatory

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

entities, including the Greater Vancouver Regional District (GVRD) and the Fraser Valley Air Quality Coordinating Committee.

Q. Have you been involved in the permitting of other similar facilities?

A. Yes. I have assisted in permitting several other natural-gas-fired power plants in Washington, Oregon, and Idaho.

<u>Emission Control Technology</u>

Q. What are the sources of emissions in the Cogeneration Project?

A. The primary sources of emissions are the natural gas-fired combustion turbines and the duct burners in the Heat Recovery Steam Generator (HRSG). The combustion of natural gas results in the emission of the criteria pollutants nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter (PM), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and a small amount of toxic air pollutants.

Other, much smaller, sources of emissions from the project are an emergency generator, a firewater pump, and a cooling tower. The emissions from the emergency generator and firewater pump are from the combustion of diesel fuel and include essentially the same pollutants as the turbines, but in much smaller amounts. The cooling tower emits PM due to the small amounts of various solids that are typically found in the cooling water.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. Please describe the emission control technology proposed for the Cogeneration Project.

A. Emission controls are directed primarily towards NO_x and CO because these pollutants are emitted in the greatest quantities. NO_x will be minimized by the use of lean pre-mix combustion turbines, and the emission control efficiency will be further improved through the use of selective catalytic reduction (SCR), where ammonia is used to reduce NO_x to nitrogen gas. NO_x emissions will be controlled to the proposed limit of 2.5 parts per million (ppm) and ammonia emissions will be limited to 5 ppm.

CO will be controlled by catalytic oxidation, where CO is oxidized to CO_2. CO will be controlled to the proposed limit of 2 ppm. The catalytic oxidation also reduces emissions of some VOCs by 30-90%.

Q. In your opinion, does the proposed emission control technology constitute the best available emission control technology ("BACT")?

A. Yes. We provided a complete BACT analysis in the PSD application, which is found in Part III, Appendix E of the Application for Site Certification. Let me briefly summarize why we believe that SCR and catalytic oxidation is BACT.

SCR is a proven emission control technology for use in natural gas-fired combustion turbine facilities and reduces the NO_x emissions to very low levels. SCR has been approved as BACT for all of the gas-fired combined cycle combustion turbine facilities permitted in Washington by EFSEC or the Department of Ecology in recent

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

years. Other experimental emission control technologies such as SCONOX and XONON are not cost-effective, and have not been proven to be technically feasible for a facility of this size.

Catalytic oxidation for the control of CO emissions is not always required on natural-gas-fired combustion turbine facilities but BP has proposed to use it in this facility. EFSEC and the Department of Ecology have concluded that catalytic oxidation constitutes BACT for similar facilities they have recently permitted. Catalytic oxidation offers the added benefit of reducing the emission of some of the VOCs by 30-90%.

Q. What emission control technology is used for particulate matter and sulfur dioxide?

A. PM and SO_2 emissions are controlled by using low ash, low sulfur fuel such as natural gas together with good combustion controls and operating practices. Low sulfur distillate fuel oil with less than 0.05% sulfur content will be used for the emergency generator and fire water pump. The levels of PM and SO_2 emissions are very low. At those low levels, there is no cost-effective post-combustion emission control technology for PM or SO_2.

The project will also incorporate ultra-low drift elimination devices in the cooling tower. They will maintain drift at a level of only 0.001% of the circulating water flow.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. How does this emission control technology compare to emission control technology proposed for other similar projects permitted or proposed in Washington State?

A. The following table compares the proposed emission limits for this project with the permit limits for other projects recently permitted by EFSEC.

	BP	Wallula	Sumas 2	Satsop
NO_x	2.5 ppm	2.5 ppm	2.0 ppm	2.5/2.0 ppm
CO	2.0 ppm	2.0 ppm	2.0 ppm	2.0 ppm
VOC	3.0 lb/hr	16.2 lb/hr	17.5 lb/hr	6.3 lb/hr
PM_{10}	20.6 lb/hr	20.8 lb/hr	23.9 lb/hr	22.6 lb/hr
SO_2	8.8 lb/hr	4.5 lb/hr	7.9 lb/hr	3.3 lb/hr
Ammonia	5.0 ppm	5.0 ppm	5.0 ppm	5.0 ppm

Emissions from the Cogeneration Project

Q. Describe the annual emissions of criteria pollutants from the Cogeneration Project.

A. For this project, we have calculated the maximum potential annual emissions, which are the maximum emissions allowed by the proposed permit limits. We have also calculated the expected annual emissions, which we believe reflect more reasonable assumptions about what the annual emissions are actually likely to be. Note that these tables provide the emissions from the cogeneration facility itself. Neither of them reflect the reductions in emissions that will occur at the BP Refinery as a result of the Cogeneration Project.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

	Maximum Potential Annual Emissions (tons/yr)				
	NO_X	CO	VOC	PM_{10}	SO_2
Total Turbines	229.4	156.8	42.2	254.4	50.9
Emergency Generator	3.4	0.9	0.16	0.09	0.0995
Firewater Pump	0.42	0.021	0.018	0.006	0.0131
Cooling Tower	N/A	N/A	N/A	7.1	N/A
Total	233.3	157.7	42.3	261.6	51.0

	Expected Annual Emissions (tons/yr)				
	NO_X	CO	VOC	PM_{10}	SO_2
Total Turbines	177.2	80.3	27.3	235.2	49.42
Emergency Generator	3.44	0.86	0.16	0.09	0.10
Firewater Pump	0.42	0.021	0.018	0.006	0.013
Cooling Tower	N/A	N/A	N/A	7.1	N/A
Subtotal	181.1	81.2	27.5	242.4	49.6
PM_{10} source test method correction				-148.5	
Total	181.1	81.2	27.5	93.9	49.6

Q. Why are the expected emissions different from the maximum potential emissions allowed by the permit?

A. There are several reasons. First, the expected emissions are calculated based on what BP expects to be a more typical annual cycle of operations, while the maximum permitted emissions are based upon the highest operating scenario BP anticipates. Specifically, the maximum potential emissions are based on the cogeneration plant operating at the maximum rate (including maximum firing of the duct burners) for 7,960 hours per year (Case 6B), 50% load for 300 hours per year (Case 1CB), 100 startup and shutdowns per year and offline for 300 hours per year for an average of 3 hours offline per shutdown.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

The expected emissions are based on the plant operating at a normal rate with normal duct firing (Case 2B) for 3,451 hours per year, normal rate without duct firing (Case 1AB) for 4,766 hours per year, forced outage for 175 hours per year, economic dispatch for 98 hours per year, and planned outage for 272 hours per year. Forced outage is when one turbine is shut down and hot started 8 hours later with the other 2 turbines operating at full load (Case 1AB). Economic dispatch is when all turbines are shut down and hot started 8 hours later. Planned outage is when all 3 turbines are shut down and cold started more than 72 hours later.

Second, the maximum permitted emissions unrealistically assume that, at all times, the facility equipment emission performance will be no better than the levels guaranteed by the equipment manufacturer. The expected emission totals assume more realistically that the equipment will perform better than the manufacturer guarantee level, as suppliers typically provide a performance margin because they must financially guarantee this performance. In this case, we have assumed that the turbines will run so that the NO_x emissions average 90% of the permit limit and CO emissions average 80% of the permit limit.

Third, the expected emissions totals take into account some recent research about the emission of particulate matter from natural gas-fired turbines. This research indicates that there is a significant amount of error in the EPA test method that is used for purposes of determining compliance with the PSD permit and that the actual particulate matter emissions are likely to be much lower than indicated using that test

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

method. This adjustment is shown in the line of the above table labeled "PM_{10} source test method correction."

Q. Can you provide some more explanation about that "PM_{10} source test method correction"?

A. Yes. Recent research indicates that the EPA test method used to measure particulate matter for purposes of enforcing PSD permit limits tends to significantly overstate the particulate matter emissions from natural gas-fired combustion turbines.

Natural gas is a very clean burning fuel. Until recently, there was little concern about particulate emissions from natural gas burning power plants. The concern about particulate matter emissions tended to focus on coal-burning power plants, which emit PM_{10} at as much as 50 times the rate of gas-fired power plants.

Let me try to explain the issue further. PSD permits issued by the regulatory agencies have generally included limits on the amount of particulate matter that could be present in the exhaust when it leaves the stack. More recently, PSD permits have begun to limit both filterable and condensable particulate matter. Filterable particulate matter is particulate that can be collected on a filter. Condensable particulate matter is made up of particles that are formed by chemical reactions that take place in the combustion turbine exhaust gas as it travels through the HRSG, emission control catalysts, and facility stack. For example, some of the sulfur dioxide (SO_2) created by burning natural gas will react with oxygen in the combustion turbine exhaust gas prior to leaving the facility stack, or after it leaves the facility stack, to form sulfate (SO_4), which is a particulate.

The EPA test method measures filterable particulate matter using a filter to trap the particulate. The test method measures condensable particulate matter by forcing the exhaust through a chilled water bath and trapping the condensable particulate in the liquid. EPA has long acknowledged that the nature of the test may result in more SO_2 being converted to SO_4 than would occur under normal conditions. When the test method is used on the exhaust from coal plants, this source of measurement error is relatively minor. However, it becomes a significant source of error for natural gas-fired plants because the amount of particulate matter in the exhaust gas is so small.

After reviewing recent research, we made some conservative assumptions to try to remove some of this measurement error. Research on this issue is on going, but we are confident that the actual PM_{10} emissions will be considerably lower than those requested as permit limits for this Project, compliance with which must be measured by the current EPA test method.

Q. Let me ask you to clarify one point. You've just testified about two sets of annual emission numbers – expected and maximum potential. Which numbers did you use for your modeling and air quality analysis?

A. All of the modeling and analyses in the application are based on the maximum potential emissions. We provided the expected numbers to give everyone a more

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

realistic estimate of the emissions. Needless to say, using the maximum potential emissions means that the modeling results overstate the impact that we expect will actually occur. I should also emphasize that the modeling ignores the emission reductions that will occur at the refinery as a result of the Cogeneration Project, with the exception of the Class I visibility modeling.

Offsetting Emission Reductions

Q. You mentioned offsetting reductions in emissions at the Refinery. What do you mean by that?

A. The cogeneration facility will send process steam to the refinery for use in its operations. As a result, the refinery will not need to operate its boilers to generate steam, which means the refinery's emissions will be reduced. The specifics of the refinery emission reductions are addressed in more detail in the Application for Site Certification and in Mike Torpey's testimony.

Q. What will be the net effect of the Cogeneration Project's emissions and the reduced emissions at the Refinery?

A. We expect that the Cogeneration Project will result in a decrease in the total emissions of criteria pollutants. We expect a significant reduction in NO_x emissions, but slight increases in emissions of the other criteria pollutants. The following table provides our best estimates.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

	NO_x	CO	VOC	PM_{10}*	SO_2	Total
Expected Annual Emissions (tons)	181	81	28	94	50	433
Expected Annual Refinery Emission Reductions (tons)	-499	-54	-3	-10	-7	-573
Net Effect (tons)	-318	27	25	84	43	-140

*Primary particulate only.

Q. The table above shows an expected increase in PM_{10} emissions, but earlier you said there would be a reduction in particulate. Can you explain how the reduction will occur?

A. We understand that people are concerned about particulate matter – both PM_{10} and $PM_{2.5}$ – so we've tried to take a close look at this issue. Particulate matter is a little more complicated than some of the other emissions because there can be both "primary" and "secondary" particulate emissions.

Primary particulate matter emissions are the particulate matter that is in the exhaust when it leaves the facility. This includes both the filterable particulate matter and the condensable particulate matter that forms by chemical reactions in the stack or immediately after the exhaust leaves the stack.

There is also something called the secondary formation of particulate. Certain substances that are emitted by burning natural gas – notably NO_x and SO_2 – are particulate "precursors." After they leave the stack, they may react with other gases in the atmosphere to form particulate matter.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

In order to understand the effect of the Cogeneration Project on ambient concentrations of PM_{10} and $PM_{2.5}$, we need to consider both the primary PM emissions and the secondary formation of PM. This is where the Cogeneration Project, with its reductions in emissions at the Refinery, differs from a stand-alone power plant. While the Cogeneration Project will result in an increase in primary emissions of $PM_{10}/PM_{2.5}$ and a small increase in secondary $PM_{10}/PM_{2.5}$ resulting from increased emissions of SO_2, it will result in a significant decrease in secondary $PM_{10}/PM_{2.5}$ formation because of the reductions in emissions of NO_x at the refinery. Here's a table showing the overall particulate matter balance.

	Primary PM_{10} Emissions	**Secondary PM_{10} from NO_x**	**Secondary PM_{10} from SO_2**	**Total**
Cogeneration Project	+ 94 tpy	+ 104 tpy	+ 21 tpy	+ 219 tpy
Refinery Reductions	- 10 tpy	- 286 tpy	- 3 tpy	- 289 tpy
Net Effect	+ 84 tpy	- 182 tpy	+18 tpy	- 81 tpy

I can explain the assumptions used in these calculations. Airshed-wide, I have assumed that 33% of the NO_X emitted will form ammonium nitrate [NH_4NO_3], which is a particulate, and I have assumed that 20% of the SO_2 emitted will form ammonium sulfate [$(NH_4)_2SO_4$], which is also a particulate. In calculating the emissions presented in the above table, I used the expected operating scenarios, rather than the maximum potential operating scenario. I think the assumptions used are reasonable, but I am also willing to acknowledge that others might use slightly

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

different assumptions. Regardless of the precise particulate matter balance, the important point is that the Cogeneration Project is not likely to adversely affect particulate matter concentrations in the airshed. In fact, it is likely to have a positive effect because secondary particulate will be lower with the power plant than without it.

Finally, I should explain that there is no distinction between PM_{10} and $PM_{2.5}$ in this discussion because we have conservatively assumed that all of the primary and secondary particulate matter at issue is $PM_{2.5}$.

<u>Existing Air Quality</u>

Q. How would you describe the existing air quality at the Cogeneration Project site?

A. As a general matter, air quality in northwestern Whatcom County and southeastern British Columbia is quite good. These areas occasionally experience days of high ozone levels, but those days are the rare exception.

Q. Can you compare the recent air quality monitoring data to state and federal air quality standards?

A. There is an air quality monitoring station in Bellingham approximately 8 miles from the Cogeneration Project site, and several monitoring stations in British Columbia that are located between 16 and 27 miles from the project site. The air quality measured at all of these monitoring stations is good. However, because the Bellingham monitoring station monitors limited data and is located in an area that is

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

much more urban that the project site, we believe the closest of the monitoring stations located in B.C. provide the best available indication of background concentrations at the project site.

Part II, section 3.2 of the Application summarizes monitoring data taken at those monitoring stations between 1999 and 2001. The following table presents the maximum values for those years, and compares them to either the National Ambient Air Quality Standard (NAAQS) or the Washington Ambient Air Quality Standard (WAAQS), whichever is more stringent.

Pollutant	Averaging Time	Background (ug/m3)	WAAQS or NAAQS (ug/m3)
SO_2	Annual 24-hour 3-hour 1-hour	3 13 27 35	53 260 1,300 1,065
PM_{10}	Annual 24-hour	13 39	50 150
$PM_{2.5}$	Annual 24-hour	9 29	15 65
CO	8-hour 1-hour	2,668 2,900	10,000 40,000
NO_2	Annual	27	100

Additional monitoring data is provided in the Application for Site Certification.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. Some residents of British Columbia have expressed concern that emissions in Whatcom County might affect air quality in British Columbia. How would you characterize air quality in the area of British Columbia north of the project site?

A. The Greater Vancouver Regional District (GVRD) monitors air quality and according to the GVRD, background air quality data from 1999-2001 from the closest monitoring stations in Canada show that the air quality is usually characterized as "good." Air quality is characterized as "fair" 1 to 5% of the time. Air quality characterized as "poor" occurs very rarely, and "very poor" never occurs.

Station	1999	2000	2001
% of hours with good air quality			
Surrey	98.5	98.0	98.0
Richmond	99.3	96.2	97.0
Langley	96.6	96.9	98.5
Abbotsford	NA	97.1	96.4
% of hours with fair air quality			
Surrey	1.5	2.0	2.0
Richmond	0.7	3.8	3.0
Langley	3.4	3.1	1.5
Abbotsford	NA	2.9	3.6
% of hours with poor or very poor air quality			
Surrey	0.0	0.0	0.01
Richmond	0.0	0.0	0.0
Langley	0.0	0.0	0.0
Abbotsford	NA	0.0	0.0

Q. Can you compare ambient air quality data from Canadian monitoring stations to Canadian air quality objectives?

A. Air quality regulation and permitting in Canada is somewhat different than in the United States. Canada and British Columbia have two different sets of regulatory

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

objectives or standards. Environment Canada, and in some cases, British Columbia have established National Ambient Air Quality Objectives. Recently, the Canadian Council of Ministers of the Environment has also adopted the Canada-Wide Standards, which are targets to be implemented by 2010.

The "metric" for the Objectives and the Canada-Wide Standards is also different. The Objectives refer to maximum values for their averaging periods, while the Canada-Wide Standards set goals for the 98th percentile value over a 3-year period.

The following table compares the maximum monitoring values from 1999-2001 to the Objectives and 98th percentile values to the Canada-Wide Standards.

Pollutant	Averaging Period	Background (ug/m3)	Canadian Objectives (ug/m3)			Canada Wide Standard
			Desirable	Acceptable	Tolerable	
SO2	Annual	3	25	50	--	--
	24-hour	13	150	260	800	--
	3-hour	27	375	665	--	--
	1-hour	35	450	900	--	--
PM10	Annual	13	--	30	--	--
	24-hour	39	--	50	--	--
PM2.5	24-hour	21	--	--	--	30
CO	8-hour	2,668	5,500	1,100	14,300	--
	1-hour	2,900	14,300	28,000	35,000	--
NO2	Annual	27	60	100	--	--
	24-hour	69	--	200	300	--
	1-hour	107	--	400	1000	--

Note: All values are $\mu g/m^3$. $PM_{2.5}$ is 98th percentile.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. Some people are concerned about PM_{10} and $PM_{2.5}$ concentrations. Can you provide a little more information about the existing concentrations of those pollutants?

A. In permit applications, we tend to focus on maximum numbers and worst-case projections of ground-level pollutant concentrations. However, it is often helpful to look at a broader range of values. The following table is based on three years of monitoring data, gathered from 1999-2001. It indicates the maximum 24-hour average concentration at the 50^{th} and 98^{th} percentiles over the three year period, as well as the maximum values.

Pollutant	50^{th} Percentile	98^{th} Percentile	Maximum	24-hour Standards or Objectives
PM_{10}	13 ug/m3	28 ug/m3	39 ug/m3	NAAQS 150 GVRD 50
$PM_{2.5}$	9 ug/m3	21 ug/m3	29 ug/m3	NAAQS 65 CWS 30

As you can see from this table, the 98^{th} percentile values are considerably lower than the maximum values, and the 50^{th} percentile or average values are much lower than that. This suggests that we should be cautious in focusing on maximum values because those maximum values are extraordinary events that are not at all reflective of typical conditions.

Effect on Air Quality

Q. What type of analysis have you performed to determine the Cogeneration Project's effect on air quality?

A. Computer modeling was performed to determine the project's effect on air quality. We used two different models. We used the Industrial Source Complex model (ISC-

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Prime) to determine pollutant concentrations in a 50-kilometer by 50-kilometer area surrounding the project site. We used the CalPuff model for the visibility analysis in the Class I areas and in Canada.

Q. Why did you use two different models?

A. They are two different types of models and they are best suited for evaluating different things.

ISC-Prime is a Gaussian plume model that is capable of calculating ground-level pollutant concentrations from multiple, spatially-separated sources of emissions located in flat or complex terrain and over a variety of weather conditions. This model was designed to be used with data from one weather station and, therefore, is easy to use to model multiple years of weather data. Five years of actual hourly weather data, taken at the BP Refinery and specifically collected to be useful in ISC modeling applications, was used. EPA and WDOE recommends the use of the ISC model with actual on-site meteorological data as a screening model in situations involving complex terrain. It is a conservative model that tends to over-predict concentrations.

The CalPuff model is what's known as a “puff” model. It does not rely on the Gaussian distribution, but instead transports the “puff” according to actual wind flow conditions. It can use data from multiple weather stations or predictive models to create a wind field. The general Pacific Northwest regional wind field, from which the wind field for the Project was extracted, was provided by the Washington

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Department of Ecology. At the time the modeling was conducted, weather data of this type was only available for one year. The CalPuff model is well suited, and approved, for modeling regional effects, such as visibility, because it can model chemical transformations. It is not as well-suited for modeling localized concentrations since predicted, not actual wind fields are used.

Q. When you performed your modeling, did you take into account the emission reductions at the Refinery?

A. With the exception of the Class I visibility modeling, no. As a conservative assumption, the modeling was performed <u>without</u> the refinery emission reductions. Even without considering these reductions, the modeled impacts fall below the Significant Impact Levels (SILs) and meet all regulatory requirements, so further modeling was not required.

The one exception was the visibility analysis using CalPuff. The initial modeling indicated that there could be a perceptible change in visibility on one (1) day when the refinery emissions reductions were not considered. We then went ahead and re-did the visibility modeling taking the refinery emissions reductions into account. The subsequent modeling showed no perceptible impact on visibility.

Q. Please explain what the modeling indicated about the effect of the Cogeneration Project emissions on ambient air quality.

A. Using the ISC model, we determined the ambient concentrations of pollutants at the maximum points of impact, which are mostly located within about 1.7 kilometers

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

(about 1 mile) of the project site. The one exception is the SO_2 annual average concentrations, where the maximum modeled impact is located approximately 12 kilometers (about 7.5 miles) north of the refinery. We compared the modeled maximum concentrations to the "Significant Impact Levels" or "SILs" established by EPA.

The SILs are a small fraction of the ambient air quality standards. EPA and the Washington Department of Ecology uses them as a screening threshold. If a project's effect is below the SILs, no further analysis is necessary to demonstrate compliance with the ambient air quality standards and PSD increments.

Pollutant	Averaging Period	Maximum Predicted Concentration	SIL
SO_2	Annual 24-hour 3-hour	0.03 ug/m3 4.3 ug/m3 8.4 ug/m3	1 ug/m3 5 ug/m3 25 ug/m3
PM_{10}	Annual 24-hour	0.25 ug/m3 4.3 ug/m3	1 ug/m3 5 ug/m3
CO	8-hour 1-hour	50.4 ug/m3 81.4 ug/m3	500 ug/m3 2000 ug/m3
NO_2	Annual	0.6 ug/m3	1 ug/m3

As you can see from the table, the project easily satisfies all of the applicable SILs.

Even though the PSD regulations do not require it, we performed some further analyses. The following table adds the maximum modeled effects of the Cogeneration Project to the maximum existing background conditions and compares the sum to the National Ambient Air Quality Standards (NAAQS) established by EPA.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Pollutant	Averaging Time	Maximum Concentration ($\mu g/m^3$)			Lower of WAAQS or NAAQS ($\mu g/m^3$)
		Modeled	Background	Total	
SO_2	Annual	0.03	3	3	53
	24-hour	1.0	13	14	260
	3-hour	5.1	27	32	1,300
	1-hour	8.7	35	44	1,065
PM_{10}	Annual	0.25	13	13	50
	24-hour	4.3	35	39	150
$PM_{2.5}$	Annual	0.25	9	9	15
	24-hour	4.3	29	33	65
CO	8-hour	12.6	2,668	2,681	10,000
	1-hour	67.3	2,900	2,967	40,000
NO_2	Annual	0.60	27	28	100
Background concentration is the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring station (see Application for Site Certification tables 3.2-8 and 3.2-9).					

Again, I want to emphasize that this modeling is for the facility emissions only. It does not reflect the emissions reductions that will occur at the refinery as a result of the Cogeneration Project.

Q. Did you also model ammonia emissions?

A. Yes. The maximum modeled ammonia 24-hour concentration was 2.8 $\mu g/m^3$. That concentration compares to the Acceptable Source Impact Level (ASIL) of 100 $\mu g/m^3$ that has been established by the Department of Ecology.

Q. Did you model impacts in British Columbia?

A. Yes. Even without taking into account the emission reductions at the refinery, the modeling indicates very low ambient impacts in Canada. The following table combines the modeled impacts with the existing maximum background

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

concentrations and compares that hypothetical total of maximums to the most stringent Canadian objective or standard. Please note that because the Canada Wide Standard for $PM_{2.5}$ is based on the 98th percentile value, this table uses the 98th percentile values for $PM_{2.5}$ instead of maximums.

Pollutant	Averaging Time	Maximum Concentration in Canada (µg/m³)			Most Stringent Canadian Objective or Standard
		Modeled	Background	Total	
SO_2	Annual	0.03	3	3	25
	24-hour	0.7	16	17	150
	3-hour	3.3	27	30	374
	1-hour	5.3	59	64	450
PM_{10}	Annual	0.2	13	13	30
	24-hour	2.5	35	38	50
$PM_{2.5}$	24-hour	0.9	18	19	30
CO	8-hour	4.8	2,668	2,673	5,500
	1-hour	13.6	2,900	2,914	14,300
NO_2	Annual	0.2	27	27	60
	24-hour	1.6	69	71	200
	1-hour	16.7	107	124	400

Notes:
$PM_{2.5}$ emissions are conservatively assumed to be equal to PM_{10} emissions.
The $PM_{2.5}$ Canada-wide standard is based on the 98th percentile averaged over 3 years, therefore, the modeled and background values indicated above are also based on these assumptions.
NO_X is considered to be fully converted to NO_2.
Excludes the effect of Refinery emissions reductions.

Q. The tables above provide information about the maximum modeled points of impact in the U.S. and Canada. Have you modeled the impact at other locations?

A. Yes. Modeling with ISC-Prime was performed on an area that extends 50 kilometers in each direction from the project site. As you would expect, the modeled impact tends to decrease as you move away from the project site. The following table

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

provides modeled impacts at some U.S. and Canadian communities in addition to the maximum modeled impact.

Modeled Maximum Concentrations (μg/m³)

	Averag-ing Time	Maximum	Birch Bay	Lynden	White Rock	Langley	Abbotsford
SO_2	Annual	0.035	0.012	0.0021	0.0094	0.0073	0.0014
	24-hour	0.98	0.48	0.10	0.19	0.14	0.058
	3-hour	4.20	2.10	0.45	0.85	0.54	0.35
	1-hour	7.70	2.80	1.20	1.70	1.40	1.04
PM_{10}	Annual	0.25	0.095	0.012	0.059	0.042	0.0079
	24-hour	4.30	1.70	0.35	0.52	0.36	0.16
CO	8-hour	5.10	3.30	0.63	1.20	0.70	0.45
	1-hour	20.0	7.20	3.0	4.40	3.62	2.68
NO_2	Annual	0.60	0.055	0.0091	0.041	0.032	0.0063
	24-hour	2.0	1.0	0.20	0.41	0.29	0.12
	1-hour	14.8	5.92	2.50	3.60	3.0	2.20

Again, I need to emphasize that this modeling is based upon the maximum permitted emissions from the Cogeneration facility. It does not consider the lower emissions actually expected to occur, and it does not take into account the significant reductions in emissions that will take place at the refinery.

We also have created maps of this area with the concentrations shown as isopleths (lines of equal concentration.) These maps show how the concentrations drop off considerably as the distance from the project site increases. Copies of these maps are provided as **Exhibit 22.1** (BRP-1)

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. Since filing the Application, have you tried to model the project's impacts in a way that would take into account the refinery emission reductions?

A. Yes. I've tried to do that for both NO_x and PM_{10}. The results of this modeling is shown in the isopleths provided as **Exhibit 22.2** (BRP-2). As you would expect, the modeled impacts are lower when the refinery emission reductions are taken into account. Let me explain a couple of things about the isopleths. First, there is one map showing isopleths of maximum annual NO_x concentrations. This map was generated by the ISC-Prime modeling, and it indicates a net reduction in NO_x levels close to the refinery. Second, there are two maps showing isopleths of PM_{10} concentrations. To evaluate both primary and secondary particulate, I had to use the Calpuff model instead of the ISC modeling. So, in order to avoid comparing apples-to-oranges (ISC-to-Calpuff), I've included one map of Calpuff isopleths showing just the modeled impact of the cogeneration facility emissions and another map of Calpuff isopleths reflecting both the facility emissions and the refinery emission reductions. Depending upon where you are in the airshed, you see either very small decreases in PM_{10} concentrations, zero impact on PM_{10} concentrations or very small increases in PM_{10} concentrations. Again, however, I should emphasize that this modeling uses the maximum permitted emission numbers.

Q. Previously you said that you expected an overall reduction of $PM_{10}/PM_{2.5}$ concentrations in the airshed. Have you performed any modeling that indicates a reduction would occur?

A. Yes. Our expectation of a net reduction in particulate matter in the airshed is based on our assumptions about expected emissions as opposed to maximum permitted

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

emissions. So, I have also modeled particulate matter using Calpuff to take into account both primary and secondary emissions, and using the expected emissions numbers rather than the maximum permitted emission numbers. The results of that modeling are shown in **Exhibit 22.3** (BRP-3). Here the map of isopleths shows small negative numbers in some areas, zeros in others, and very small positive numbers in others. This modeling confirms that the project is unlikely to have any meaningful adverse effect on air quality, and will slightly improve air quality in some places.

Q. Based on your modeling, what's your conclusion about the impact of the project?

A. The cogeneration facility will have very little impact on existing air quality, even when the emission reductions are not taken into account. In the United States, the impacts are all below the Significant Impact Levels. Impacts are even lower in Canada and will not significantly contribute to adverse or unhealthy air quality levels. When the emissions reductions are taken into account, I would expect the facility to actually have a slightly positive effect on existing NO_x and particulate matter levels in the airshed.

Q. Have you modeled ozone?

A. No. Regulations in Washington do not require ozone to be modeled in connection with individual air permitting decisions. Where ozone is a concern, it is a regional issue with many chemical reactions from emissions of several different pollutants

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

from many individual sources contributing to its formation. For that reason, ozone modeling is usually performed on a regional scale by regulatory agencies.

Furthermore, we did not think it would be necessary or appropriate to model ozone in this instance because the Cogeneration Project will result in a net reduction in NO_X emissions, a precursor chemical for ozone.

Start-up Emissions

Q. Some individuals have asked questions about Start-up and Shut-down emissions. Can you explain the issue concerning those emissions as you understand it?

A. Historically, air permitting has focused on typical operating scenarios for generating facilities. However, for these types of facilities the emission rates are different during startup and shutdown of the facility. During startup, the rate of NO_X, CO and VOC emissions can be higher because the catalysts used for controlling these emissions are not fully effective until they have warmed up. At the same time, less fuel is burned and the duct burners are not firing. The rate of PM and SO_2 emissions are both lower because those emissions are directly related to the amount of fuel being burned. All emission rates are lower during shutdown, so that is not really an issue.

Q. What will the emissions be during start-up and shut-down?

A. The following table shows the emissions during startup and shutdown. There are three different types of startups; hot, warm and cold. Hot starts are those starts that

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

are achieved less than 8 hours after the last time the turbine was shut down. Warm starts are those that occur 8 to 72 hours after shutdown, and cold starts are those that occur 72 hours or more after shutdown. For all three types of startups, the first turbine starting has different startup times and emissions as the 2nd and 3rd turbines. Shutdowns are identical for all three turbines.

Startup Emissions (lbs/event)	Hot Start	Warm Start	Cold Start	Shutdown
1st Turbine				
Duration (min.)	60	112	187	30
NOX	88	173	257	19
CO	287	420	490	114
PM10	13	28	49	5
SO2	2	4	8	1
VOC	24	53	94	13
2nd Turbine				
Duration (min.)	45	67	97	30
NOX	84	109	175	19
CO	351	454	733	114
PM10	9	15	23	5
SO2	1	3	4	1
VOC	15	27	43	13
3rd Turbine				
Duration (min.)	45	72	102	30
NOX	84	119	184	19
CO	351	477	752	114
PM10	9	16	25	5
SO2	1	3	4	1
VOC	15	30	48	13
Total				
Duration (min.)	105	192	307	30
NOX	256	401	616	19
CO	989	1351	1975	114
PM10	30	58	97	5
SO2	5	10	16	1
VOC	55	110	184	13

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. Did you take these emissions into account in the modeling you discussed above?

A. No. The modeling that is presented in the Application and discussed above does not evaluate startup emissions.

Q. Is it possible to use the computer models to determine the effect of startup emissions on ambient air quality?

A. Yes it's possible, but I want to emphasize that the model has some difficulty predicting ambient impacts as a result of brief changes in emission rates. The ISC-Prime model is what is called a steady-state model, where emissions and stack conditions are expected to remain constant over a period of time. Startup and shutdown conditions are, by definition, not steady-state as the stack flow, temperature, and emissions are all changing over short periods of time.

Q. Have you modeled the start-up emissions?

A. Yes. We modeled both hot start and cold start scenarios. We did not model a warm start scenario, because its impacts would be less than the hot and cold scenarios. Since the emissions and stack conditions change throughout a start, we divided the starts into three portions; ramp to 100% speed and low load (5-10%), hold at low load, and ramp to 50% load. Separate emissions and stack conditions were then modeled for each of the three startup portions and the impacts were added together to get the total impact.

The maximum predicted impacts in the U.S. and Canada are shown in the following table, and compared with the U.S. and Canadian short-term ambient air quality

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

standards and objectives. Again, it is important to keep in mind that this modeling does not take the refinery emission reductions into account, and also conservatively combines the maximum startup impacts with the maximum background concentrations.

Maximum Modeled Impacts in the U.S.

Pollutant	Averaging Time	Maximum Concentration (µg/m³)			Lower of WAAQS or NAAQS (µg/m³)
		Modeled	Background	Total	
SO_2	24-hour	0.6	13	14	260
	3-hour	3.2	27	30	1,300
	1-hour	4.1	35	39	1,065
PM_{10}	24-hour	1.6	35	37	150
$PM_{2.5}$	24-hour	1.6	29	31	65
CO	8-hour	47	2,668	2,715	10,000
	1-hour	584	2,900	3,484	40,000

Background concentration is the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring station (see Application for Site Certification tables 3.2-8 and 3.2-9).
In the United States, there is no short-term (24-hour or 1-hour) NAAQS for NO_2.

Maximum Modeled Impacts in Canada

Pollutant	Averaging Time	Maximum Concentration in Canada (µg/m³)			Most Stringent Canadian Objective or Standard
		Modeled	Background	Total	
SO_2	24-hour	0.6	16	17	150
	3-hour	2.5	27	30	374
	1-hour	3.3	59	62	450
PM_{10}	24-hour	1.5	35	37	50
$PM_{2.5}$	24-hour	1.5	18	20	30
CO	8-hour	27	2,668	2,695	5,500
	1-hour	340	2,900	3,240	14,300
NO_2	24-hour	2.0	69	71	200
	1-hour	87.4	107	194	400

Notes:
$PM_{2.5}$ emissions are conservatively assumed to be equal to PM_{10} emissions.
The $PM_{2.5}$ Canada-wide standard is based on the 98th percentile averaged over 3 years, therefore, the modeled and background values indicated above are also based on these assumptions.
NO_X is considered to be fully converted to NO_2.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Q. Does this modeling change your conclusions about the potential impact of the Cogeneration Project on ambient air quality?

A. No. Short-term impacts were modeled for SO_2, PM_{10}, CO and NO_x. The SO_2 and PM_{10} impacts are lower for startup conditions than for normal operation. The CO impacts are higher for startup conditions, but still well below the SILs. Short-term NO_x impacts are elevated, but are still well below the Canadian objectives and there are no short-term NO_x limits in the United States.

<u>Visibility</u>

Q. What analysis have you performed to determine the Cogeneration Project's impact on visibility?

A. We performed two different analyses for visibility, one for the U.S. and one for Canada. Both analyses used the CalPuff model. The U.S. evaluation focused on the visibility at Class I areas while the Canadian analyses focused on specific lines of site identified by the air quality staff of the Greater Vancouver Regional District (GVRD).

Q. What were the results of the modeling for Class I areas in the U.S?

A. Visibility in the Class I areas in the U.S. was performed with the CalPuff model. PM, NO_X, and SO_2 were modeled, with chemical transformations of secondary pollutants such as ammonia nitrate and ammonia sulfate, and the results were combined to calculate a visibility coefficient. The results were then compared with background data to find a visibility change, in percent. The federal land managers

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

consider over 5% to be a perceptible change in visibility and over 10% to be unacceptable.

The following table shows the results of the visibility analysis. When emission reductions are not taken into account, only one day at one Class I area has a visibility change over 5%. When emission reductions are taken into account, the maximum visibility change is 2.3%

Class I area	Maximum Visibility Change (%)	Number of days over 5%	Maximum Visibility Change including Boiler Emissions Reductions	Number of days over 5%
Olympic National Park	6.0	1	1.9	0
North Cascades National Park	2.6	0	1.5	0
Alpine Lakes Wilderness Area	4.1	0	2.3	0
Glacier Peak Wilderness Area	4.4	0	2.1	0
Pasayten Wilderness Area	1.8	0	1.2	0
Mt. Baker Wilderness Area	4.1	0	2.3	0

Q. Explain the results of the modeling for lines of site in British Columbia?

A. Visibility modeling in Canada was performed differently. The calculated visibility coefficient was averaged over a line of sight, generally from a valley floor to a mountain peak. The modeled lines of sight were established by GVRD. The modeled visibility was compared with background data to determine if any additional days will have impaired visibility as compared to current conditions. The following table shows that the project will have no detrimental impact on visibility along these lines of sight.

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888

Line of Sight	Number of days with impaired visibility, background conditions	Additional days with impaired visibility due to Cogeneration Project	Maximum visibility change
1	171	0	1.2%
2	166	0	2.4%
3	166	0	2.1%
4	166	0	2.2%
5	166	0	2.7%
6	166	0	1.5%
7	166	0	1.4%

END OF TESTIMONY

PERKINS COIE LLP
1201 Third Avenue, Suite 4800
Seattle, Washington 98101-3099
(206) 583-8888